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REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN	§ §	**PUBLIC UTILITY COMMISSION OF TEXAS**

**COMMENTS OF
ROBERT L. BORLICK
ON THE
ACEEE WHITE PAPER**

COMES NOW Robert L. Borlick, Senior Energy Advisor with Borlick Energy Consultancy, who comments the White Paper submitted by the American Council for an Energy-Efficient Economy (ACEEE), dated October, 2021.

ABOUT THE AUTHOR

Robert L. Borlick is an energy consultant with more than 40 years of experience related to the electric power industry. He previously held partner-level positions in two international consulting firms: Putnam, Hayes & Bartlett, Inc, and Hagler, Bailly, Inc. He also served as a Senior Advisor with the Brattle Group. From 2005 through 2013 he assisted the Midwest Independent System Operator in developing its energy-only market and its demand response programs, including the preparation of MISO's filings in the FERC dockets that gave rise to Orders 719 and 745. From 1989 through 1998 he assisted the governments of Great Britain, Singapore, India, Australia, New Zealand, and Canada, with the development of their competitive electricity markets.

EXECUTIVE SUMMARY

This White Paper contains a wealth of information. Unfortunately, it also contains some serious flaws. In particular, it claims that energy efficiency programs will improve long-run ERCOT power system reliability. They will not. However, the demand response programs described in the White Paper could improve system reliability, depending on how they are designed.

The White Paper also produces estimates of cost savings that include double counting, and other conceptual errors, that casts doubt on their numerical credibility. Despite these errors, the estimates almost certainly undervalue the benefits offered by energy efficiency and demand response programs to the state of Texas. Thus, the White Paper is successful in highlighting the huge potential of these programs.

THE DEEP DIVE

I was looking forward to reading this White Paper because I staunchly support energy efficiency and demand response. Unfortunately, the analysis it presents suffers from a number of serious flaws.

IMPACT ON ERCOT SYSTEM RELIABILITY

The White Paper's most significant flaw is its claim that the proposed energy efficiency programs will significantly improve the long-run reliability of the ERCOT power system. Assuming the authors define improved reliability as reducing the probability of ERCOT resorting to rolling blackouts, the claim is unfounded.

Energy efficiency programs will indeed reduce peak demand, and initially reduce the frequency and duration of supply scarcity events; however, at the same time they will also reduce the scarcity rents that generators rely on to recover their fixed costs, thereby reducing the incentive to add new capacity. ERCOT relies on this homeostatic process to balance the entry of new supply (or the deferral of existing plant retirements) with forecasted future demand. So when energy efficiency reduces future demand it also reduces the future supply of generation capacity to satisfy that demand. Although these demand reductions can temporarily increase reliability, in the long run their effect on power system reliability will be negligible.

The White Paper *de facto* acknowledges that its energy efficiency programs will reduce supply resources by quantifying the savings derived from generating capacity deferrals - but it does not acknowledge that this conflicts with its claim that power system reliability will also be increased. This conflict is illustrated in the White Paper when it increases the peak load reductions by 16 percent to calculate how much generating capacity could be deferred while still retaining ERCOT's 16 percent reserve margin.[1] But if the reserve margin remains unchanged so does ERCOT system reliability. The proposed programs cannot simultaneously improve ERCOT system reliability while

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[1] The 16 percent reserve margin assumed in the White Paper (Table ES-1) is based on a misconception. Market forces determine the ERCOT reserve margin, not some prescriptive entity, because ERCOT lacks a capacity market. ERCOT staff only estimate reserve margins for future years based on the load forecast, existing supply resources and what knowledge it has of likely future supply resource additions and retirements. The actual ERCOT reserve margin varies significantly from year to year.

at the same time deferring all of the claimed 8,990 MW of generating capacity.[2]

In the near term it is possible that demand reductions can temporarily improve system reliability but only until developers of new supply resources and owners of existing resources adjust to the revised, lower load forecast. Thereafter, the impact of past energy efficiency programs will indeed reduce the generating capacity requirement but will have little effect on system reliability. To be sure, energy efficiency can cost-effectively reduce capacity and energy costs and therefore is desirable - but that is a separate argument.

In contrast, demand response programs can improve ERCOT system reliability, depending on how they are implemented. For example, if load interruptions are delayed until the energy market price is at the $9,000 per MWh cap, the program will have maximum effect increasing power system reliability. On the other hand, if loads are interrupted before, or shortly after, ERCOT begins dispatching into operating reserves, the program will reduce scarcity rents, thus will have minimal impact on system reliability. Between these two extremes the impact on power system reliability needs to be quantified through explicit modelling.

In 2012 the Brattle Group modelled the impact of demand response on ERCOT system reliability and demonstrated how demand response can reduce scarcity rents.[3] However, the modelling was crudely done and is suggestive rather than definitive. Today the ERCOT staff has the capability of doing more sophisticated assessments of various demand response programs using the Strategic Energy Risk Valuation Model (SERVM) provided by Astrapé Consulting.

THE BENEFIT-COST ANALYSIS IS FLAWED

Most benefit-cost analyses are simple discounted cash flow (DCF) calculations consisting of an initial investment followed by a stream of annual costs and benefits, each of which is discounted at a rate that reflects the riskiness of that cash flow.[4] The difficult part is forecasting the size of each

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2 The White Paper also claims that 13,242 MW of generating capacity serving the winter peak could be saved but this is not so because ERCOT is a summer peaking system..

3 The Brattle Group, "ERCOT Investment Incentives and Resource Adequacy," a study prepared for ERCOT, June i, 2012, pp. 70-71.

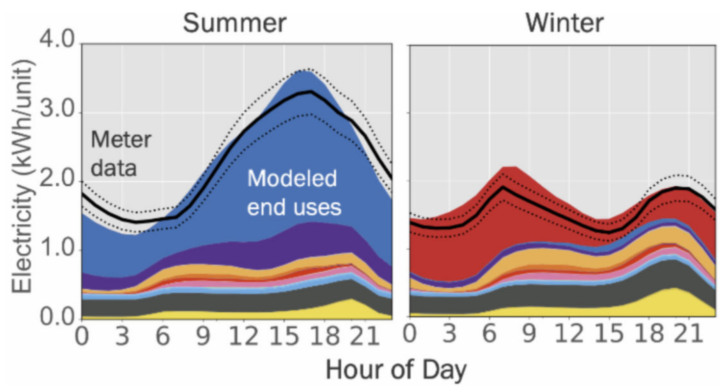
4 Often there is significant option value in deferring an investment decision to take advantage of time resolving uncertainty regarding either the cost of the investment or the benefits it will produce. This is certainly true for energy efficiency and demand response programs because they defer investment in new generation. In light of the rapid changes in costs of renewables and storage, plus technology advances in green hydrogen and next generation nuclear

cash flow, since they occur in the future and typically depend on forecasts of other (uncertain) random variables.

For example, the heat pump substitution program proposed in the White Paper requires a forecast of the amount of electric energy saved in each future hour multiplied by the price of electric energy in that hour, then summing the hourly products over the useful life of the heat pump. What complicates this calculation is that the amount of energy saved, and the hourly wholesale market price of electric energy, will synchronously vary with outside temperature. The significance of this correlated behavior is important and addressed below.

Models exist for forecasting the hourly energy savings from various energy efficiency programs. Figure 1 illustrates the type of data available from NREL's ResStock Model.[5]

Figure 1- Sample of Hourly Residential End-Use Loads in Texas



Source: Lawrence Berkeley National Laboratories

Furthermore, some years will have mild summers and/or winters while others will be harsh. That will require running multiple scenarios, then probability-weighting them to get the expected annual values of the energy savings. The SERVIM model available to ERCOT can run alternative weather

reactors, that option value should not be ignored.

The inclusion of option value is lucidly described in: Dixit and Pindyck, Investment Under Uncertainty, Princeton University Press, 1994.

[5] The National Renewables Energy Laboratory (NREL) developed and maintains the *ResStock* and *ComStock* models, which project hourly energy consumption for various end uses. Also, Lawrence Berkeley National Laboratories (LBNL) developed its *Time-Sensitive Value Calculator,* which combines hourly energy use load shapes with forecasted hourly energy prices to produce the avoided cost estimates.

years and do the probability-weighting.

The White Paper authors did not do the rigorous calculation described above. Instead they multiplied the expected lifetime energy saved by a single, load-weighted average price that ERCOT forecasted for just one year (2021).[6] Furthermore, they only calculated the savings using average prices for the peak summer and peak winter hours.[7] This might be acceptable if the kWhs of energy saved through energy efficiency and the ERCOT wholesale market prices were statistically independent random variables, but they are not.[8]

To understand why the two variables are not statistically independent consider this: when the outside temperature is low the hourly kWh savings will be high, but (generally) so will ERCOT's contemporaneous energy market prices because total ERCOT load will (generally) also be high. This same phenomenon occurs during the Summer months with respect to air conditioning.[9]

In all fairness, the White Paper authors may have felt constrained to follow the prescribed Texas methodology (which also appears to be flawed and may deserve to be revisited).[10]

Another conceptual error is in tacitly assuming that future ERCOT market energy prices would remain unchanged (even if in constant dollars). ERCOT market prices are largely determined by market prices of natural gas, which are highly volatile and uncertain. Further price uncertainty is contributed by operating reserve shortage surcharges that get added when supply resources are short.

Lastly, the White Paper double counts the energy efficiency savings by adding the avoided cost of

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[6] White Paper, "we value demand reductions and energy savings at the PUCT official avoided costs of $80/kW-year (one kW of power available over one year) and $0.10/kWh saved (Harris 2020)," p. 7.

[7] Section 25.181(d)3(A) of the Texas Administrative Code states, "By November 1 of each year, ERCOT shall file the avoided cost of energy for the upcoming year for the ERCOT region, as defined in §25.5(48) of this title (relating to Definitions), in the commission's central records under the control number for the energy efficiency implementation project. ERCOT shall calculate the avoided cost of energy by determining the ***load weighted average*** of the competitive load zone settlement point prices for the ***peak periods covering the two previous winter and summer peaks.***"

[8] Statistics theory informs us that the expectation of two statistically independent random variables $\tilde{\mathbf{A}}$ and $\tilde{\mathbf{N}}$, is equal to the product of the expectations of the two random variables, i.e., $E\{\tilde{\mathbf{A}} \bullet \tilde{\mathbf{N}}\} = E\{\tilde{\mathbf{A}}\} \bullet E\{\tilde{\mathbf{N}}\}$.

[9] This assumes that a high efficiency heat pump would also produce energy savings in the summer relative to the typical air conditioning unit it replaces but those savings would surely be smaller than those produced in the winter season.

[10] This statement is only suggestive because I have not examined the Texas methodology in detail.

generating capacity to the avoided cost of energy.[11] On first impression this appears reasonable - until one recalls that ERCOT is an energy-only market, which pays for generating capacity through the energy rents that generators collect during hours when operating reserve are in short supply. The avoided costs of generating capacity are already captured in the avoided cost of energy.[12]

It is understandable that ACEE's limited budget necessitated cutting corners to produce a quick-and-dirty benefit-cost analysis but the White Paper should have emphasized the "ball park" nature of their cost savings estimates.

OTHER CONCERNS

Other concerns raised by the White Paper include the following:

- Overvaluing winter peak load reductions
- Applying only the Utility Cost Test
- Not recognizing the role key of Retail Electricity Suppliers
- Socializing subsidies to program participants.

This list is not meant to be comprehensive but only to illustrate the need for a more refined analysis of energy efficiency and demand response within the ERCOT footprint.

Overvaluing Winter Peak Reductions

ERCOT is a summer peaking system so the generation, transmission and distribution capacities must be sized to accommodate the maximum summer loads. Although ERCOTs' maximum peak demand might have occurred during winter storm URI if customers had not been curtailed (we can never know for sure), that storm was a once-in-30-years event. It is not practical to design a system

[11] It is noteworthy that the White Paper does not include the avoided costs of transmission and distribution network capacities while overestimating the avoided cost of generating capacity.

[12] The authors of the White Paper display their lack of understanding of basic power system economics by claiming that the annual carrying charge of a new gas-fired combustion turbine (GCT), or that of a new gas-fired combined cycle (GCC), determines the avoided cost of generating capacity. That's incorrect because both types of plants will have lower heat rates than the existing GCTs; consequently, the new plants will earn energy rents that partly offset their carrying charges, producing lower "net capacity costs." They further assert that the avoided cost would be higher if determined by a GCC plant because of its higher annual carrying charge. This is not so because the GCC's lower heat rate will produce energy rents that more than offset its higher carrying charge. Whether a new GCT or a new GCC determines the avoided capacity depends on how far out of equilibrium the power system's generation mix is - and in which direction - but in neither case will the capacity cost of either resource be equal to its annual carrying charge.

to deliver unimpeded service during events that seldom occur.

Reducing the winter peak loads may indeed have some value in relieving localized network congestion but arbitrarily assigning 25 percent of the capacity savings to the winter peak reduction is almost certainly excessive.

Applying only the Utility Cost Test

The California Standard Practice Manual describes five tests for evaluating demand-side management programs, including the Utility Cost Test.[13] However, the most comprehensive ones are the Total Resource Cost Test and the Societal Cost Test.[14] The former captures all of the global monetary costs and benefits while the latter adds the value of non-monetized externalities, such as avoided greenhouse gas emissions.

By applying only the Utility Cost Test the White Paper does not fully capture the costs and benefits of its proposed programs. For example, the detailed calculations in the White Paper's Appendix indicate that the subsidies for the energy efficiency programs only cover a portion of the investments required to implement each program, leaving the customer to cover the rest out-of-pocket. The White Paper's benefit-cost analyses appears to exclude those costs.

On the other hand, the White Paper does not quantify the benefits derived from reducing fossil fuel plant emissions (Methane, CO2, NOx, SOx, particulates, and others). By excluding them the White Paper substantially underestimates the programs' benefits.

Not Acknowledging the key Role of Retail Electricity Suppliers

The White Paper does not acknowledge the key role of competitive Retail Electricity Providers (REPs) with regard to energy savings. This is important because REPs supply most of the electric

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[13] California Energy Commission, "CALIFORNIA STANDARD PRACTICE MANUAL: ECONOMIC ANALYSIS OF DEMAND-SIDE PROGRAMS AND PROJECTS," July 2002.

The Standard Practice Manual is not without shortcomings. It fails to account for a program participant's response to the effective reduction in the cost of the energy service that energy efficiency produces, which causes the observed "snap back" effect. This effect reduces the energy savings but it also increases the customer's well-being. That customer benefit is captured by the "Customer Value Test." Despite being apprised of this failing by multiple parties, the California Energy Commission has not corrected the Manual.

[14] J. Lazar and K. Colburn, "Recognizing the Full Value of Energy Efficiency," Regulatory Assistance Project, Sept 2013, p. 13.

energy to retail customers and will initially be the beneficiaries of the monetary savings derived from load reductions, particularly in hours when ERCOT wholesale market prices are highest.

When a customer reduces its load in an hour when the ERCOT real-time market price exceeds the energy price in the customer's contract the REP gains from not having to purchase the curtailed energy at the real-time price and reselling it to the customer at a loss.[15] The converse is also true: when a customer reduces its load in an hour when the ERCOT real-time market price is below the energy price in the customer's contract the REP avoids having to buy the curtailed energy at the real-time price but loses the revenue that energy would have produced at the higher contract price.

To the extent that REPs can forecast the future load reductions from energy efficiency they can accommodate them by adjusting their contract prices (and competition among REPs will cause this to occur). However, forecasting the load reductions produced by opportunistic dispatching of demand response resources in hours when real-time prices are high is difficult, if not impossible. While this can be viewed as a problem it is actually an opportunity because it provides the basis for both the REP, and its customers that reduce loads in response to higher market energy prices, to mutually benefit from those load reductions. I described such a demand response program in a previous filing in this docket.[16]

There is a need for an explicit mechanism that shares REP profits derived from opportunistic load reductions with the customers that produced those load reductions. Traditional interruptible load programs run by TDSUs will not provide that mechanism.

The most efficient and effective way to structure an interruptible load program is for the REP to credit its customers for their interrupted energy at a high percentage (e.g., 80 to 90 percent) of the ERCOT real time market price.[17] Furthermore, the ideal arrangement is where the customer specifies the price points at which he/she is willing to incur various levels of load interruption. Such a program design would maximize economic efficiency while also maximizing the attractiveness of

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[15] This is true even if the REP is fully hedged because it can sell unsold, contracted energy into the real time market and realize the same profit.

[16] Robert L. Borlick, "Comments of Robert L. Borlick," Public Utility Commission of Texas, Project 52373, Review of Wholesale Electric Market Design," August 19, 2021, pp. 3 - 5.

[17] Each REP would determine its own specific "give back" percentage based on what the competition is offering. In theory, crediting the customer with the full market price is the most efficient pricing scheme but there has to be an incentive for the REPs to voluntarily participate in the demand response program.

participating in the program and the program's retention rate.

The demand response program just described still leaves a significant role for TDSUs, i.e., to subsidize most of the costs of smart thermostats and other enabling devices that allow customers to automate their responses.[18] Without these automation devices participation in demand response programs will not be maximized. TDSUs are the logical entities for subsidizing enabling devices because they are guaranteed full cost recovery. In contrast, the REPs will hesitate investing in these devices knowing that the participating customers may migrate to other REPs when their contracts are up for renewal.

Socializing the Program Subsidies

The White Paper treats the combined cost savings of a TDSU and its customers' REPs as if they accrue solely to the TDSU. In fact, the TDSUs will capture only a fraction of these cost savings, i.e., the costs of deferring network capacity expansion. Thus, if a TDSU is providing all of the program subsidies it will almost certainly have to raise its delivery charges, thereby producing cross-subsidies between program participants and nonparticipants.

Requiring a nonparticipating customer to subsidize his neighbor's energy efficiency improvements is inequitable, particularly so if the nonparticipant does not utilize inefficient electric heating. One can justify such cross-subsidies if they increase delivery charges by modest amounts but that is unlikely to be the situation if a large percentage of total residential households in Texas receive subsidies for insulating their homes, and/or switching to expensive heat pumps and water heaters.

An alternative to subsidies is for the TDSUs to provide program participants with low interest loans that they pay back, through surcharges on their monthly bills that are less than their bill savings, over the useful life of their respective energy efficiency or demand response investments. Being regulated, low-risk entities, TDSUs have access to cheap debt capital and are assured of repayment because, short of going "off-grid," the customers cannot avoid these payments.

SUMMARY

Despite its stumbles, this White Paper correctly highlights the huge potential for cost-beneficial

[18] Requiring customers to bear some nominal share of the cost will screen out those who do not seriously intend to use the enabling devices.

residential energy efficiency and demand response programs in Texas. Although its benefit-cost analysis suffers from multiple shortcomings, it almost certainly undervalues the benefits that energy efficiency and demand response programs can deliver.

The PUCT should facilitate the development of energy efficiency and demand response by working through the REPs and the TDSUs. But this will require additional, more detailed and more rigorous analyses than that presented in the White Paper.

Respectfully submitted,

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